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Ground Distance Relaying: Problems and Principles

GROUND DISTANCE RELAYING: PROBLEMS AND PRINCIPLES

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INTRODUCTION

The single line to ground fault is the most common type of fault that occurs on transmission lines, and ground distance functions are often used for the detection of these faults. However, ground distance functions do have acknowledged limitations and special consideration should be given to the design and application of the functions. This paper will discuss the operating principles of ground distance functions and some of the limitations, or problems, that can be encountered in their application.

Ground distance functions measure an apparent impedance to the fault based on the ratio of relay voltage to relay current. A variety of ground distance relay characteristics have been used: reactance, mho, and quadrilateral for example.

The simplest ground distance functions use only a single phase current and a single phase voltage. As the design of ground distance functions has improved, other currents and voltages have been added to the relay operating quantities. This paper will discuss distance functions of the "Phase angle comparator" design as discussed in the next section. A "classical" mho unit has two inputs: an operating signal (IZ - V), and a polarizing signal (VPOL). Some of the newer relay designs employ three or more inputs to the coincidence logic. These additional inputs greatly improve the performance of the relay, but they may require a more complex test setup to insure that all of the inputs have the proper phase relationship.

DEVELOPMENT OF THE MRO CHARACTERISTIC

INPUT SIGNALS

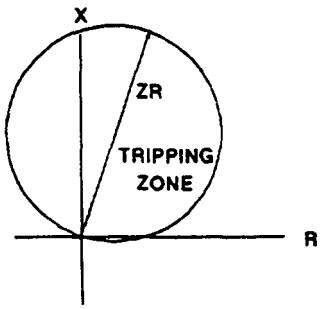
Mho distance type characteristics may be developed by measuring the phase angle between two or more voltage signals in the relay.

The logic used to measure the phase angle is called a Phase Angle Comparator. For the simplest two input comparators, the voltage signals in the relay are referred to as the operating signal and the polarizing signal. These signals are derived from the system voltage and the system current supplied to the relay.

In an analog relay, the relay current is converted to a voltage in the relay, typically by a transactor. A transactor is an iron core reactor with an air gap. The transactor produces a voltage proportional to the input current. The transfer impedance of the transactor is defined as ZR, and is used to determine the reach and angle **of maximum reach of the mho characteristic. Other techniques may be used in digital relays: for example, the I·ZR** - V and V signals may be developed using a digital Fourier filter. The Fourier produces a phasor output: that is, the **I·ZR** - V and the V have both magnitude and phase angle. The phase angle comparator is a software module that checks if the relative phase angles of the operating and polarizing signals are within the tripping range, based on the desired characteristic.

Mho distance characteristics are typically plotted as circles on an R-X impedance diagram as shown in Figure l. However, because the mho characteristic is actually determined by the angle between voltage phasors, it is convenient to plot the

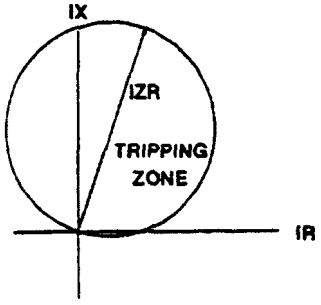
TYPICAL MHO CHARACTERISTIC



R-X IMPEDANCE DIAGRAM

Figure 1

TYPICAL MHO CHARACTERISTIC



IR-IX VOLTAGE DIAGRAM

Figure **2**

characteristics on a voltage diagram ***to*** describe how they are derived. The voltage diagram may be obtained from the R-X diagram by multiplying all the points by the fault current in the relay as shown in Figure 2. Since the fault current will change as the system conditions and fault location change, the voltage diagram will contract or expand for different fault currents. The

voltage phasors, however, will have the same phase angle and magnitude relationships as the impedance vectors on the R-X diagram.

Consider the simple system shown in the one line diagram of Figure 3. Let ZR be the reach of the mho function, ZF be the impedance from the relay location to the fault, and V and I be the current and voltage supplied to the relay. For the fault on Figure 3, the voltage V supplied to the relay will be I·ZF. The current I supplied to the relay is transformed into a voltage I·ZR by the action of the transactor. The actual current and voltage used by the mho function depend upon the individual relay.

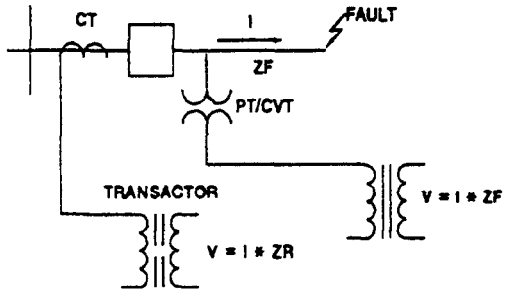
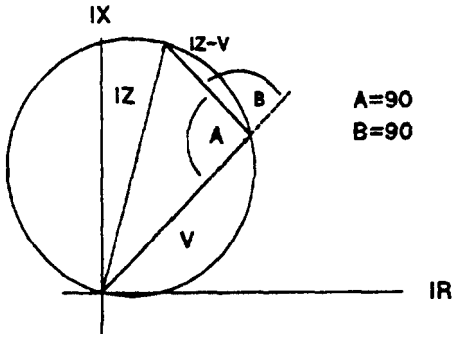


Figure 3

THE IR-IX DIAGRAM

The "Classical" mho characteristic is shown as a circle on the IR-IX diagram, passing through the origin as shown in Figure 4. The diameter of the circle which passes through the origin is referred to as the "angle of maximum reach", or in Electra-Mechanical relay terms, the "angle of maximum torque". The angle of maximum reach of the circle, I·ZR is determined by the replica impedance of the function, ZR. If the voltage phasor V shown on Figure 4 is the voltage supplied to the relay under fault conditions, then the position of V is along the angle of the impedance to the fault, ZF. The magnitude of V will therefore depend on the fault location. For a fault at the balance point of the relay, the V will plot on the mho circle as shown in Figure 4.

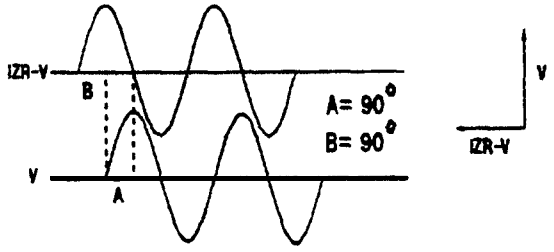
From geometry it is known that if one side of a triangle inscribed in a circle is the diameter of the circle, then the angle opposite the diameter is 90 degrees. Since I·ZR is the diameter of the circle, both angles A and B in Figure 4 are equal to 90 degrees. Two sides of the triangle are formed by the phasors V and I·ZR, the third side is the phasor difference of these signals, I·ZR - V, which is known as the operating signal of the mho function. The locus of all points for which the phasors V and I·ZR - V are 90 degrees apart, is a circle that passes through the origin. The phasor V is known as the polarizing signal. For the classical mho function, also known as



BALANCE POINT

Figure 4

a self-polarized mho, this voltage is the fault voltage used to form I·ZR - V. Sine wave signals representing V and I·ZR - V are shown in Figure 5 corresponding to the phasors of Figure 4. For this condition, I·ZR - V leads V by 90 degrees.



MHO CHARACTERISTIC BALANCE POINT

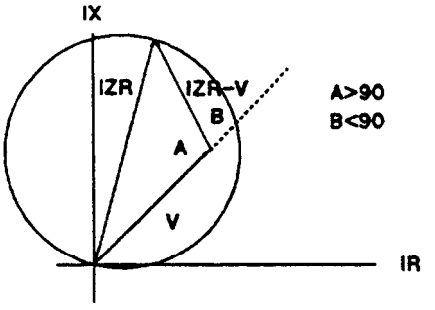
IZR-V LEADS VBY 90 DEGREES

Figure 5

If the fault is moved closer to the relay, that *is,* inside its zone of protection, the magnitude of V will decrease relative to the magnitude of the I·ZR as shown in Figure 6. For this condition, the angle A is greater than 90 degrees while the angle B is less than 90 degrees. For this condition, as shown in Figure 7, I·ZR - V leads V by less than 90 degrees. As the fault is moved farther from the relay, that is, outside its zone of protection, the magnitude of V will increase relative to the magnitude of the I·ZR as shown in Figure 8. For this condition, the angle A is less than 90 degrees while the angle B is greater than 90 degrees. For this condition, as shown in Figure 9, I·ZR - V leads V by more than 90 degrees.

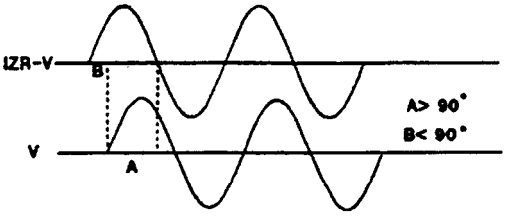
The fault is within the mho function's zone of protection if I·ZR - V leads or lags V by 90 degrees or less. This is

depicted in Figure 10. Thus a mho characteristic can be created if the phase angle between these two signals can be accurately measured.



INTERNAL FAULT

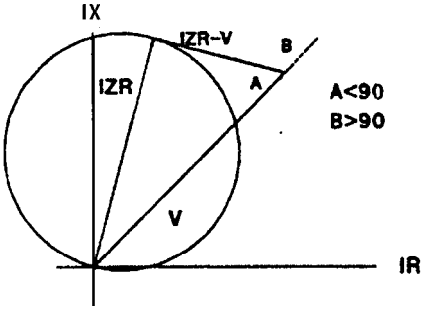
Figure 6



INTERNAL FAULT

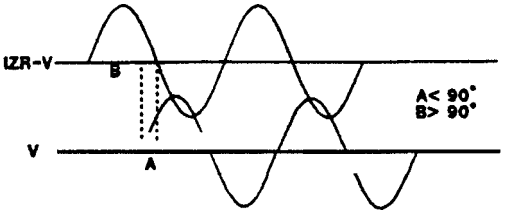
RR-V LEADS V BY LESS MAN 90 DEGREES

Figure 7



EXTERNAL FAULT

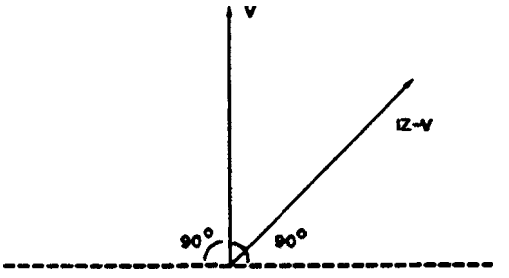
Figure 8



EXTERNAL FAULT

IZR-V LEADS V BY MORE THAN SO DEGREES

Figure 9

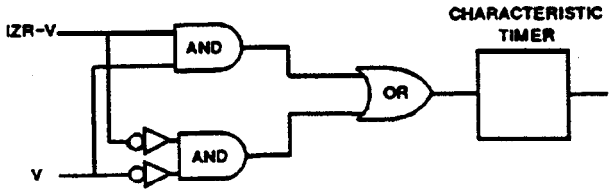


RANGE OF OPERATING ANGLES

Figure 10

PHASE ANGLE COMPARATOR LOGIC

Phase Angle Comparator Logic is used to measure the phase angle between I·ZR - V and V in the implementation of the mho function. The phase angle comparison can be an analog circuit or software. A simple phase angle comparator circuit is shown in Figure 11. This circuit is typical of the comparator used in all analog solid state GE mho distance relays. This type of circuit measures the coincidence between the operating and polarizing waveforms. Coincidence occurs when both signals have the same instantaneous polarity, as determined via the AND functions of Figure 11. The coincidence blocks are directed to the input of the characteristic timer shown in Figure 11; the characteristic timer produces an output if the duration of the coincidence is longer than its pickup setting. For a circular mho characteristic the pickup of the timer is set for 90 electrical degrees, or 4.16 milliseconds for a 60 hertz system.

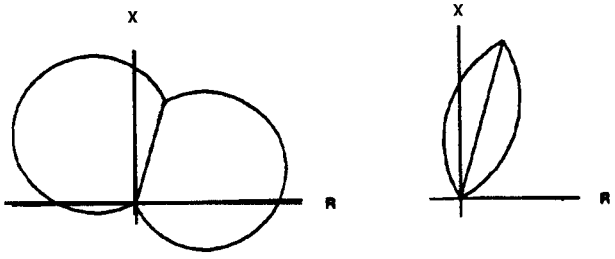


PHASE ANGLE COMPARATOR

t 2 INPUT I

Figure 11

The shape of the mho characteristic on the R-X diagram may be modified by changing the pickup setting of the characteristic timer. Figure 12 shows the effects of increasing and decreasing the setting from 90 degrees. The lens characteristic is created by increasing the pickup setting to a value greater than 90 degrees: the expanded mho is the result of a pickup setting less than 90 degrees.



PICKUP < 90 DEGREES PICKUP > 90 DEGREES

EFFECT OF CHARACTERISTIC TIMER SETTING

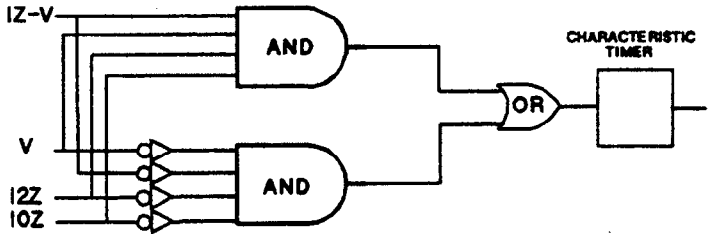
Figure 12

The Phase Angle Comparator may be used to develop relay characteristics other than the mho characteristic by changing the input signals. Table I shows a selection of various ground relay characteristics that can be obtained from a simple two input Phase Angle Comparator.

TABLE I

CHARACTERISTIC	OPERATING SIGNAL	POLARIZING SIGNAL
MHO	**IZ-v**	**V**
REACTANCE	IZ-v	IZ
DIRECTIONAL	IZ	V

The design of the phase angle comparator ground mho distance function can be extended to include more input signals as shown in Figure 13. In this case, the coincidence between all of the input signals must be at least equal to the characteristic timer setting. This implementation includes several characteristics: the IZ-V and V form a mho characteristic, the IZ-V and 12Z form a negative sequence reactance characteristic, and the IZ-V and the IOZ form a zero sequence reactance characteristic



FOUR INPUT PHASE ANGLE COMPARATOR

Figure 13

OPERATING QUANTITIES

Ground distance relays are typically designed to be set based on the positive sequence impedance to the fault for single line to ground faults. The impedance seen by the relay is a combination of the positive, negative, and zero sequence impedances of the system. The positive and negative sequence impedances are generally equal to each other in magnitude and angle while the zero sequence impedance may have both a different magnitude and angle. Because of this, ground distance relays generally employ some form of "zero sequence current, compensation" to adjust the measured impedance to reflect the actual system impedances.

The operating quantity on GE relays is typically compensated as shown:

$$(IA - IO)\cdot ZRl + KO\cdot IO\cdot ZRO - VAG \qquad (1)$$

Where:
IA is the faulted phase current
IO is the zero sequence current
VAG is the faulted phase voltage
ZRl is the relay positive sequence replica impedance
ZRO is the relay zero sequence replica impedance
KO is the zero sequence current compensation factor

Since IA is equal to IA1 + IA2 + IAO, where IAl, IA2, and IA0 are the sequence current components referenced to IA, the operating quantity may also be expressed as:

$$(IA1 + IA2)\cdot ZRl + KO\cdot IO\cdot ZRO - VAG \qquad (2)$$

The sequence network connections for the radial single line to ground fault of Figure 14 are shown in Figure 15. In the design of most GE relays, the magnitude of ZRl and ZRO are equal by design. The current compensation factor, KO, is a scalar set equal to the ratio of the magnitude of the zero sequence impedance of the protected line to the magnitude of the positive sequence impedance of the protected line.

Table II shows the currents and voltages for a phase A to ground fault at the end of the protected line of Figure 15. Assume that the reach of the ground relay is set equal to the line length, 6 ohms. The apparent impedance seen by a compensated relay can be calculated by:

$$\frac{VAG}{IA1 + IA2 + KO \cdot IO} \qquad (3)$$

Note that the KO used in equation 3 is a phasor rather than the scalar used in equations 1 and 2. This is to account for the angular difference in the positive and zero sequence impedances.

TABLE II

11	=	1.95 A l-79.8'
12	=	1.95 A /-79.8°
IO	=	1.95 A f-79.8'
VA	=	58.3 v /-0.8°
IA	=	5.85 A /-79.8°

KO = Z0L/ZlL = 3 /10°

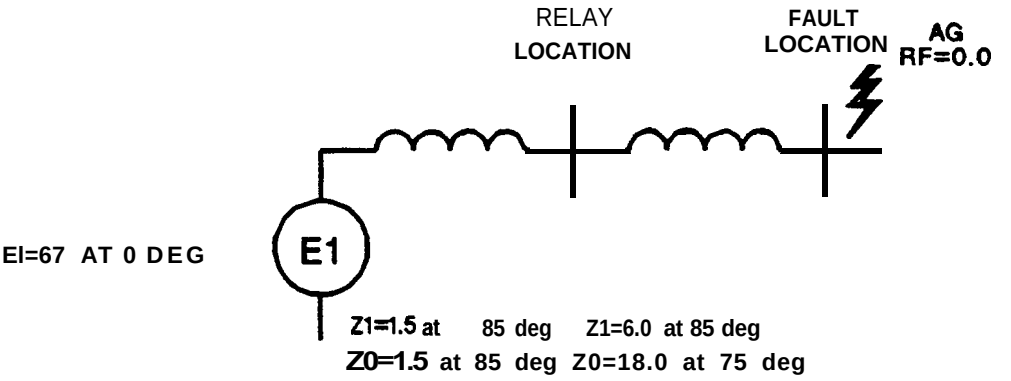


Figure 14

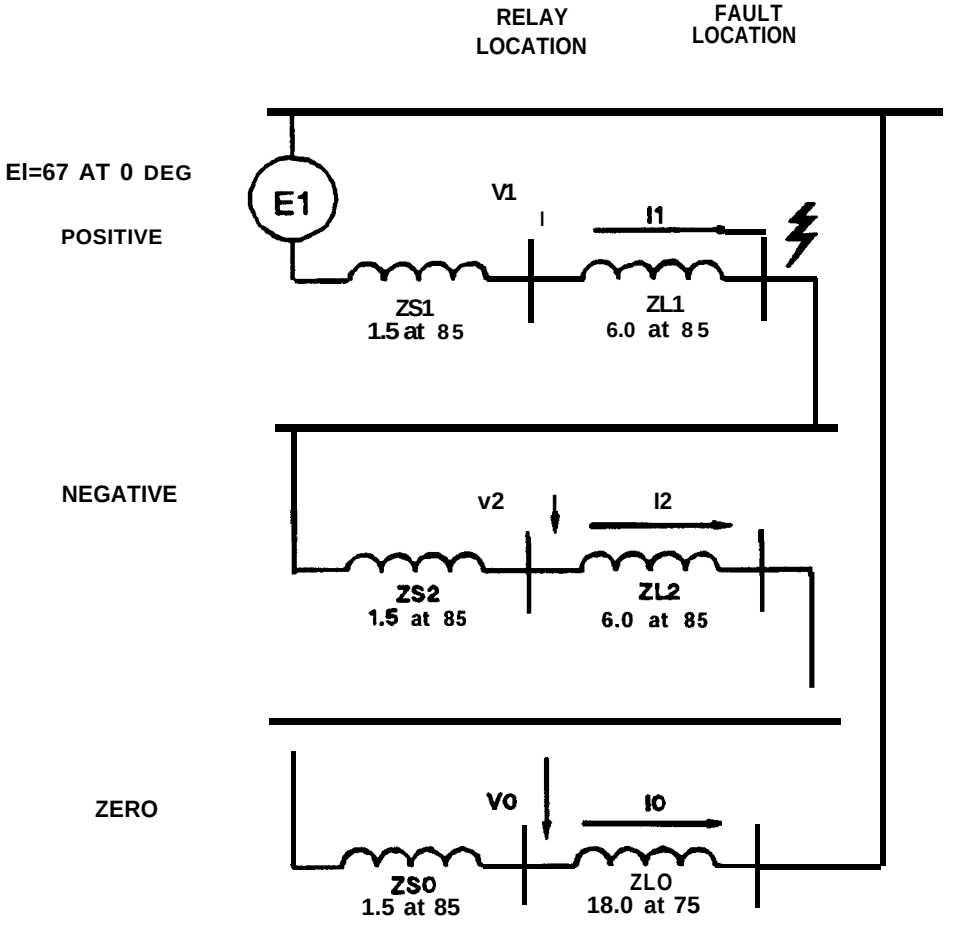


Figure 15

The apparent impedance given by Equation 20 is equal to 6 ohms at 85 degrees. If the impedance had been calculated by simply dividing the phase A voltage by the phase A current, the result would have been 10 ohms at 79 degrees, which of course is not the correct positive sequence impedance to the fault.

POLARIZING QUANTITIES

A mho distance relay function may be developed using a variety of voltages as the polarizing signal. The Classical, or self-polarized, mho function discussed thus far uses the faulted phase voltage as the polarizing signal. That is, a phase A ground function would use VA, and a phase AB phase function would use VAB. The resulting mho characteristic, when plotted on the R-X diagram, remains invariant under changing system and fault conditions. In 1949, A. R. van C. Warrington published his classic paper "Graphical Method for Estimating the Performance of Distance Relays During Faults and Power Swings" [10]. The methods presented in this paper are widely used to visualize the performance of distance relays on the R-X diagram. However, Warrington's paper contains the following sentence:

> "It must be remembered, however, that distance relays polarized by potential other than the one used for the restraint windings have a family of circles for different fault conditions and hence their characteristics are more difficult to show on an impedance diagram."

Most modern relay designs use part or all of the unfaulted phase voltages in the polarizing signal. This is often referred to as "cross polarization@', or "healthy phase polarization". Thus the actual mho characteristics of the relay do not have an invariant plot on the R-X impedance diagram: rather, they possess an infinite number of characteristic plots which vary based on power system conditions and fault type.

POLARIZING SIGNAL REQIUREMENTS

The primary requirement for the polarizing voltage is that the pre-fault phase angle of the polarizing signal be the same as that of the restraint voltage used in the operate signal. It is also desirable that, if possible, the polarizing voltage magnitude during a fault will be sufficient for the mho function to operate steady state during a fault in which the faulted phase voltage is zero. Consideration should also be given to the effect on the distance relay if a fuse in the secondary of the potential device fails. When a ground distance mho function is used in a single phase tripping scheme there is an additional requirement: the polarizing voltage on the sound phases should

not be affected by the lack of voltage, or by spurious voltage, on the open phase during the open pole period following a single phase trip.

Before attempting to determine the "ideal" polarizing voltage for a ground distance unit, performance criteria on which to base the decision must be selected. Depending upon the intended application of the relay, the following points may be of importance:

a. Operation for zero voltage ground faults
b. Directional integrity
c. Fault resistance/arc impedance accommodation
d. *Correct* phase selection in single phase tripping schemes
e. Proper operation with one phase open in single pole tripping schemes

MEMORY ACTION

In the "Classical" mho unit, the polarizing voltage is the same as the restraint voltage used in the operate signal: the faulted phase voltage. This presents a problem when a fault is applied to the line at the relay location, since the faulted phase voltage goes to zero magnitude (neglecting arc/fault impedance). In order to overcome this situation, "memory" circuits were added. The memory circuit is designed to provide a "remembered" voltage, based on the prefault voltage, to the relay for a long enough time to allow the function to operate for an internal fault. This circuit would typically be a tuned circuit in electro-mechanical relays, an active bandpass filter in static relays, and some form of digital memory in a microprocessor based relay. The time duration of the memory action is determined by the design of the particular relay. Relay designs that use "cross polarization", or "healthy phase polarization", may not require memory action for single line to ground faults since the polarizing voltage will not go to zero. However, for a three phase fault, all voltage to the relay is removed and thus memory action is still required for three phase faults if the ground distance functions must operate for three phase faults.

A side effect of the memory action is the introduction of a time varying response in the mho unit: that is, the response, or "characteristic", initially following a fault is not the same as the "steady state" response, or characteristic. This will be discussed in more detail in a subsequent section.

CHARACTERISTIC TERMS

As was mentioned earlier, mho distance functions typically have more than one characteristic during fault conditions when viewed on an R-X diagram. GE uses several terms to describe these characteristic as explained below.

Dynamic Characteristic: The dynamic characteristic is the initial characteristic of a time varying impedance characteristic. The variation with time is due to the memory action of the relay.

Variable Characteristic: The variable characteristic of a mho function is due to the use of some form of healthy phase polarization. The characteristic varies as a function of the relay design, the power system, and the fault type. The variable characteristic does not vary with time.

Steady State Characteristic: The steady state characteristic is the Classical mho characteristic that passes through the origin on the R-X diagram. this is the mho characteristic that is typically plotted during routine relay testing. Depending upon the relay design, this characteristic may, or may not, exist during actual fault conditions.

All of these characteristics may exist in the same relay design. The mho function may have a variable characteristic, a dynamic characteristic, and a steady state characteristic, as well. Both the dynamic and variable mho characteristics include more area on the R-X diagram than the Classical Mho circle. The dynamic characteristic and the steady state characteristic for a faulted phase polarized ground unit are shown in Figure 16. It should be noted here that although the characteristic includes an area below the R axis, the unit is still directional. The mho function will only operate for faults below the R axis if they are capacitive faults in front of the relay (that is, in the "trip" direction).

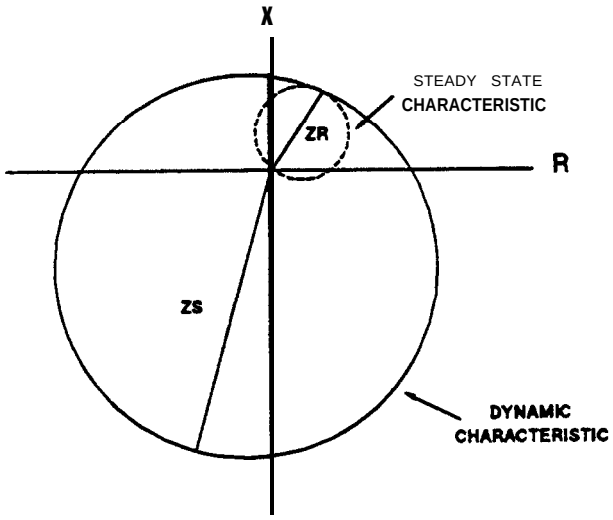


Figure 16

CHOICE OF POLARIZING SIGNALS

There has been a wider variety of polarizing voltages used in ground distance functions than in the phase distance functions. Although the types of polarizing signals discussed in this paper will be limited, it must be recognized that other voltages may be used. Typical signals for a phase A function are:

(VAG)M : faulted phase voltage with memory

(VBC ∠ 90°)M: quadrature voltage: phase BC voltage rotated 90 degrees with memory.

(VAM)M : median, phase A to the midpoint of VBC with memory.

(VAGl)M : positive sequence voltage referenced to phase A with memory.

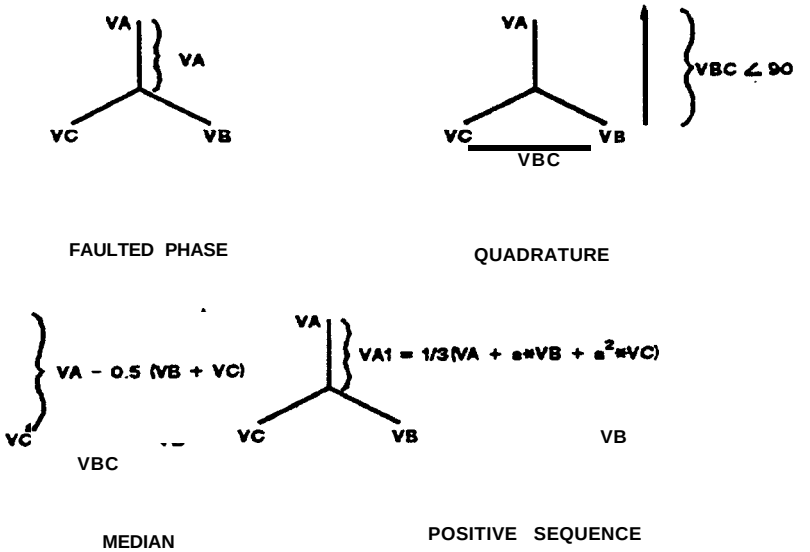


Figure 17

The size of the variable characteristic is a function of the choice of polarizing voltage, the power system configuration, and the fault type. Consider the simple radial system of Figure 18.

Figure 19 is a plot of the dynamic and variable characteristics of four ground distance units with different polarizing voltages for the same single line to ground fault. The dynamic characteristic is the same for each of these relays, and is the same as the variable characteristic for quadrature polarized function. The greatest fault resistance coverage is provided by the quadrature polarized unit: the least by the faulted phase polarized unit. The equivalent source impedances used to

determine the variable characteristics for these conditions are :

	POLARIZING VOLTAGE	EQUIVALENT SOURCE IMPEDANCE
Faulted Phase'	: 0	
Median	:	**(1/3)·Z0S**
Positive Sequence	:	(1/3)·(Zls + ZOS)
Quadrature	:	**(2/3)·Zls + (1/3)·ZOS**

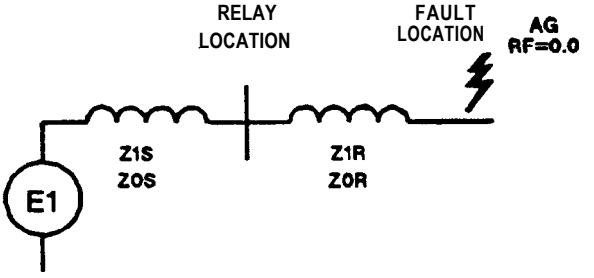


Figure 18

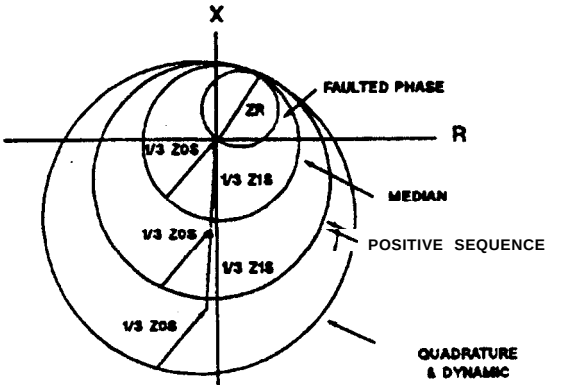


Figure 19

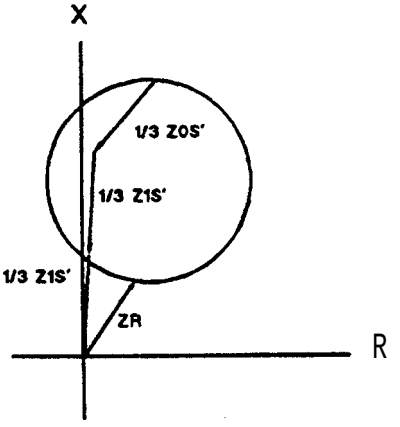


Figure 20

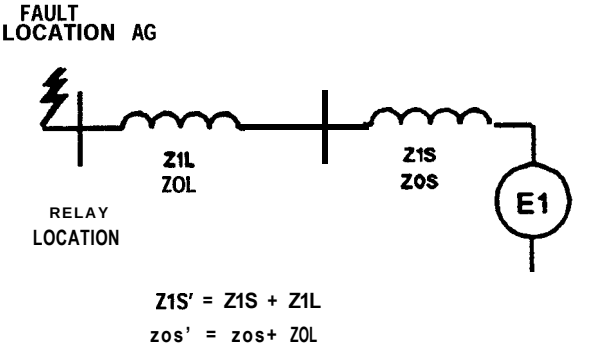


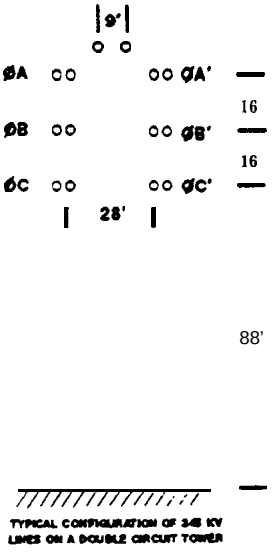
Figure 21

As was stated previously, these variable and dynamic characteristics remain directional even though the plot extends below the R axis. In fact, the relays possess a totally different characteristic lot for faults in the reverse direction. Figure 20 shows t e plot of the quadrature polarized mho function for a single line to ground fault behind the relay location, as shown in Figure 21.

EFFECTS OF MUTUAL INDUCTION ON GROUND DISTANCE RELAYS

MUTUAL INDUCTION

When two or more lines are in parallel on the same right of way, fault current in one line may induce voltages in the parallel line or lines. A typical configuration of 345 KV lines on a double circuit tower, with close coupling, is shown in Figure 22. Typical self and mutual impedances are shown in Table III.



TYPICAL CONFIGURATION OF 345 KV LINES ON A DOUBLE CIRCUIT TOWER

Figure 22

TABLE III

Z1	=	0.06	+ j 0.59	ohms/mile
Z0	=	0.55	+ j 1.96	ohms/mile
ZlM	=	0.01	+ j 0.05	ohms/mile
ZOM	=	0.49	+ j 1.30	ohms/mile

Zl : Positive sequence self impedance
Z0 : Zero sequence self impedance
ZlM : Positive sequence mutual impedance
ZOM : Zero sequence mutual impedance

The zero sequence mutual impedance is about two-thirds of the zero sequence self impedance. By contrast the positive and negative **sequence** mutual impedances are on the order of one-twelfth of the self impedances. Consequently, the positive and negative sequence mutual impedances can usually be ignored in the application of distance relays. The zero sequence mutual impedance, on the other hand, is significant and its effect on ground distance relays must be considered.

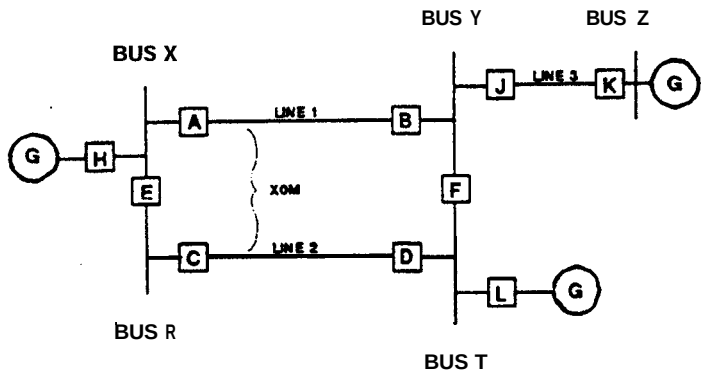
EFFECT ON DISTANCE MEASUREMENT

Depending on the power system configuration in the vicinity of the relay location, the presence of mutual induction will cause a ground distance relay to see an apparent impedance that is larger than or smaller than the actual impedance to the fault. A typical system involving mutual coupled lines is shown in Figure 23. Two cases will be cited in which the mutual coupling between

lines 1 and 2 will cause a ground distance relay on line 1 at breaker A to see a smaller impedance:

Case 1: Tie breaker F open, a single line to ground fault at bus Y, and the zero sequence current in line 2, from D to E, is a large percentage of the zero sequence current in line 1.

Case 2: Breakers C and D are open, a single line to ground fault at bus Y, and grounding chains are used at both ends of the line to ground all three phase conductors.



TYPICAL EXAMPLE OF MUTUAL COUPLING BETWEENPARALLEL LINES

Figure 23

Either of these conditions increases the zero sequence current that flows in line 1 over the value that would be expected without mutual induction. This increase in the zero sequence current may cause a ground distance relay to overreach because of the reduction in the apparent impedance. This is of particular concern in the application of first zone ground distance relays since they should not trip under these conditions. It may be necessary to modify the relay settings to prevent this undesirable operation. The percentage overreach for the conditions of Case 1 and 2 are calculated in Appendix I.

When the currents in the protected line and the parallel line(s) are flowing in the same direction the apparent impedance seen by a ground distance function will be larger than it actually is as cited in Case 3 below.

Case 3: All breakers are closed, a single line to ground fault on bus Y.

The important consideration here is to be certain that an overreaching ground distance relay used in a stepped distance or pilot relaying scheme will operate for a fault on the remote bus, with adequate margin. The results of Case 3 in Appendix I shows that the apparent impedance seen by a ground distance function at

breaker a for an end-of-line fault is equal to 74 percent of the actual impedance to the fault (a 26 percent underreach). Therefore, to see this end of line fault, a ground distance function at breaker A would have to have a setting greater than 135 percent of the actual line impedance. Sufficient margin would have to be added to this setting to insure operation for all line faults.

It is theoretically possible to compensate a mho ground distance relay such that the effect of the zero sequence mutual on its reach will be minimal. This is typically accomplished by injecting a portion of the zero sequence current from the parallel line into the relay to offset the increase or decrease in the zero sequence voltage induced in the line. However, mutual compensation may be undesirable or impossible for one of the following reasons:

a) Where lines run parallel for a portion of their total length, but do not terminate at the same substation at one or both ends, it is not possible to obtain the zero sequence current from the parallel line.

b) In what may be the most severe condition of zero sequence mutual coupling, the case where the parallel line is open and grounded at both ends, it is not possible to obtain the zero sequence current from the parallel line for use in the compensation circuit since the grounding point is usually beyond the current transformer location.

c) The use of mutual inductance compensation may cause the distance unit to lose directionality. This can occur on a close in fault on the parallel line, where the zero sequence compensation current may overpower the actual line currents and allow the ground distance relay to operate for a reverse fault.

EFFECT OF FAULT RESISTANCE

The effect of resistance in the fault is dependent on the type of fault.

In faults not involving ground, the resistance is made up of the arc products alone and it has been predicated that a constant voltage (equal to about 5 percent of normal system voltage) is maintained across the arc [12]. The resistance is therefore non-linear and can be estimated to be equal to about 5 percent of the total impedance from the fault back to the source behind the fault (5 percent of ZSL as shown in Figure 24A). Phase distance functions will be most affected by arc resistance for conditions of high source to line impedance ratios (ZS/ZL) wherein the resistance can appear to be large relative to the line impedance.

In faults involving ground, there is a linear component of resistance in addition to the non-linear arc component. This linear component can be introduced by tower footing resistance, ground wire resistance, trees growing into the line, etc. For ground faults, therefore, the voltage drop across the fault resistance will be directly proportional to the total current in the fault. In addition, infeed, load flow and non-homogeneity (system impedance angles are different) will modify the effect of the resistance on the relay performance.

Figure 24 will be used to demonstrate the effects of infeed. load and non-homogeneity. An IR-IX diagram is used, which is the same as an R-X diagram if the current is neglected.

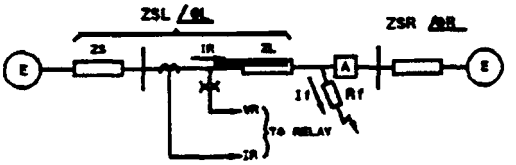
For the system shown in Figure 24A, the voltage seen by the relay at the left will be:

$$VR = IR\angle\theta R \cdot ZL\angle\theta L + If\angle\theta F \cdot RF\angle 0 \qquad (4)$$

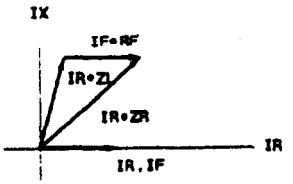
Let IR be the reference so that $\theta R = 0$, then

$$VR = IR \cdot \left(ZL\angle\theta L + \frac{IF\angle\theta F \cdot RF}{IR}\right) \qquad (5)$$

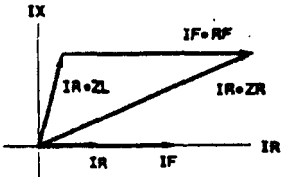
$$ZR = \frac{VR}{IR} = ZL\angle\theta L + \frac{IF\angle\theta F \cdot RF}{IR} \qquad (6)$$



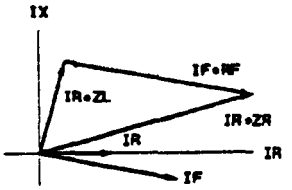
A. TYPICAL POWER SYSTEM



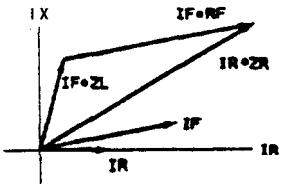
B. BREAKER A OPEN



C. BREAKER A CLOSED, NO LOAD, HOMOGENEOUS SYSTEM



D. BREAKER A CLOSED, LEFT-TO-RIGHT LOAD. OR OL < OR



E. BREAUER A CLOSED, RIGHT-TO-LEFT LOAD. OR OL > OR

Figure 24 · Effect of load flow and system non-homogeneity on fault resistance

If breaker A is open, the system is radial, and the relay current, IR, is equal to and in phase with the current in the fault resistance, IF. The fault resistance appears to be purely resistive and it adds directly to the line impedance as shown in Figure 1B.

If breaker A is closed, the current in the fault resistance, IF, is greater than the relay current, IR, which causes the resistance to appear larger than it actually is (by the ratio of IF/IR). With no load flow and a homogeneous system, IR and IF will be in phase and the resistance will be magnified but not shifted in phase as shown in Figure 24C. Load flow or system non-homogeneity causes IF and IR to be at different angles which introduces an apparent reactive component to the magnified resistance as shown in Figures 24D and 24E.

Exactly how a ground distance function will respond to resistive faults is dependent on the type of function (reactance versus mho) and on the method used to polarize the function.

Different methods of polarizing mho ground distance functions were described earlier in this paper. As previously shown, a healthy-phase polarized function produces an expanded characteristic that is dependent on the source behind the function. Load flow was not considered for those plots. When load flow is accounted for, the characteristics are shifted as shown in Figure 25.

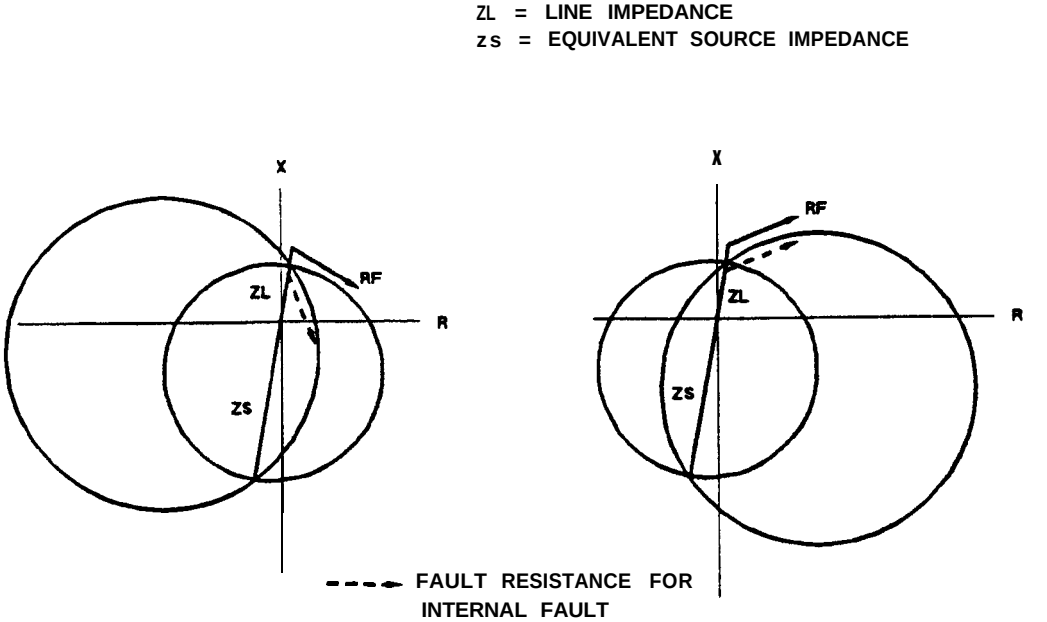


Figure 25 · Effect of Load Flow on Mho Distance Function

Note that the characteristics shift in the same direction as the shift in the fault resistance. For the external fault, there is no tendency by the mho function to either underreach or overreach regardless of the direction of the load flow. For internal faults the shift is in the proper direction to provide optimum protection for resistive faults.

Reactance functions can be affected similarly. The performance of a phase-current polarized and a negative sequence current polarized reactance function is shown in Figure 26.

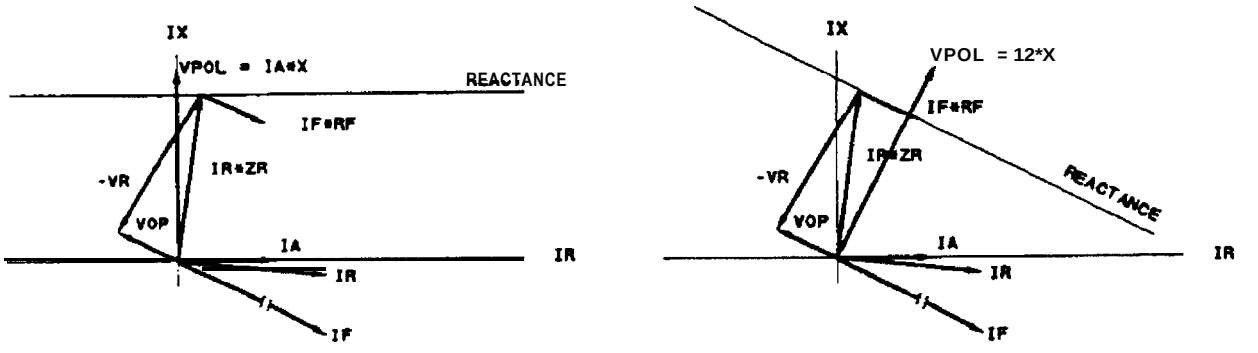
For the system shown in Figure 24a, the following parameters were used:

EL = 67 V /0° ER = 67 V /-30°
ZR = 6 n /88° RF = .5 n /0°

Left Source	Transmission Line	Right Source
Z1S = 1.5 Ω /88°	Z1L = 6 /88°	Z1S = 1.5 n /88°
Z0S = 1.5 n /88°	Z0L = 18 n /88°	zos = 1.5 n /88°

Because the system impedances are all at the same angle (88 degrees), this is a homogeneous system. Note that the reach of the functions is set equal to the line impedance and that the fault is at the end of the line (a balance point fault). The

VPOL = POLARIZING QUANTITY
IR = RELAY CURRENT (Il+I2+K0*I0)
ZR = RELAY REACH (POSITIVE SEQUENCE)
VR = RELAY VOLTAGE (FAULTED PHASE)
VOP = OPERATING QUANTITY (IR*ZR - VR)



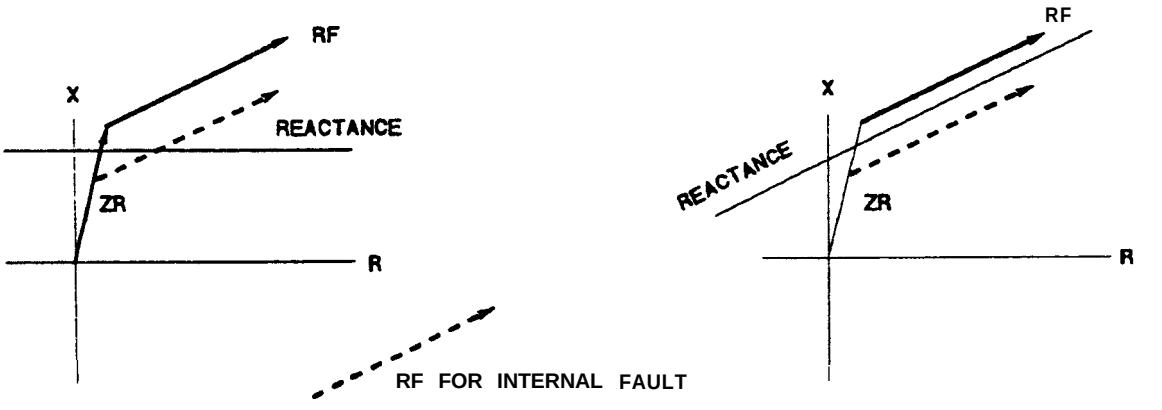
A. PHASE-CURRENT POLARIZED B. NEGATIVE SEQUENCE CURRENT POLARIZED

Figure 26 - Effect of Left-to-Right Load Flow on Reactance Functions

relay current is the compensated current **(I1+I2+K0·I0).** The reactance functions shown will operate when the operating quantity (VOP) is within 90 degrees of the polarizing quantity (VPOL).

A phase-current polarized function can overreach as demonstrated in Figure 26A. Overreach comes about because the fault current is shifted with respect to the phase current which is being used to polarize the function.

The response of a negative sequence current polarized reactance function is shown in Figures 26B. Note that the characteristic shifts in the same direction as the fault resistance and that there is no tendency to overreach such as displayed by the phase-current polarized function. The shift in the characteristic is always in the direction to provide optimum coverage for internal faults with resistance. The overreach is eliminated because the phase relationship between the negative sequence current polarizing quantity and the total fault current is not affected by load flow. If the system is not homogeneous, the negative sequence fault current will be shifted relative to the total fault current which will in turn cause a tendency for the function to either overreach or underreach depending on the impedance relationships. The shift in the fault resistance is not as severe as caused by load and the functions can be designed to eliminate overreaching.



A. PHASE-CURRENT POLARIZED

B. NEGATIVE SEOUENCE CURRENT POLARIZED

Figure 27 · Effect of Right-to-Left Load Flow on Reactance Functions

Figure 27 shows the effect of right-to-left load flow. Note that the phase-current polarized function would underreach for these conditions.

It has been shown that ground distance functions do provide coverage for fault resistance with the amount of coverage being

dependent on the type and design of the function. However, they can not be relied on to provide coverage for extremely high resistance ground faults such as encountered for fires under the line, trees growing into the line, etc. If these faults are of concern, ground directional overcurrent functions should be used to provide the required coverage.

TYPICAL PROBLEM AREAS FOR GROUND DISTANCE RELAYS

The discussion thus far has involved the performance ground distance functions for single line to ground faults. Although the ground distance functions are designed primarily for detecting single line to ground faults, they may respond to other fault types as well. The following are examples of fault and system conditions that may cause ground distance relays to fail to perform as expected. The mho units in the examples are "self-polarized", but the problems may exist even if cross polarization is used.

POSSIBLE LOSS OF DIRECTIONALITY ON EXTERNAL LLG

As discussed previously, the purpose of the zero sequence current compensation factor in the operating quantity is to allow the ground distance relay to measure the proper impedance to the fault based,on the positive sequence impedance of the line. However, this same zero sequence current compensation factor may cause a misoperation of, the forward looking element on the unfaulted phase during an external double line to ground fault.

Consider the system of Figure 28 with a BCG fault on the bus at terminal B. Typical settings for the Zone 1 and Zone 2 ground distance relays at B are shown in Table IV. The current and voltage signals at Breaker 3 for the external BCG fault are shown in Table V.

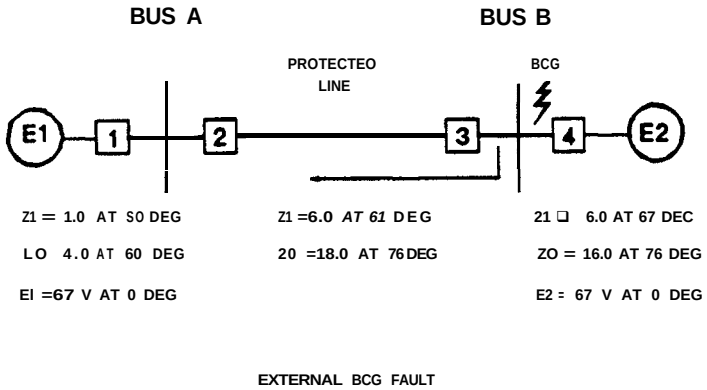


Figure 28

TABLE IV

Zone 1	Zone 2
ZRl = 5.4 n	ZRl = 9.0 n
ZRO = ZRl	ZRO = ZRl
/ZR1 = 87°	/ZR1 = 87°
/ZR0 = 76°	/ZR0 = 76°
K0 = 3	K0 = 3

TABLE V

Sequence	Phase
I1 = 5.5 A /94°	IA = 0.08 A /-81'
12 = 4.1 A /-89'	IB = 8.9 A /-12°
IO = I.5 A /-78°	xc! = 8.2 A /-162'
V1 = 28.6 V f-1.6'	VA = 85.7 V /-1.6'
V2 = 28.6 V f-1.6'	VB = 0.0 v /0"
V0 = 28.6 V /-1.6°	vc = 0.0 v /0°

Consider a simple Zone 2 phase A ground distance relay at Breaker 3 looking towards Bus A having an operating quantity of:

$$(IA - I0)\cdot ZRl + K0\cdot ZR0 - VAG \qquad (7)$$

The voltage phasors comprising the operating signal are shown in Figure 29; The (IA -I0)·ZRl term is neglected because of its low magnitude. Note that if the magnitude of the zero sequence current term is larger than that of the restraint voltage VAG, this unit will operate. For the conditions of this example, the positive sequence impedance reach of the function would have to be increased to approximately 29 ohms, or almost 500% of the positive sequence impedance of the protected line.

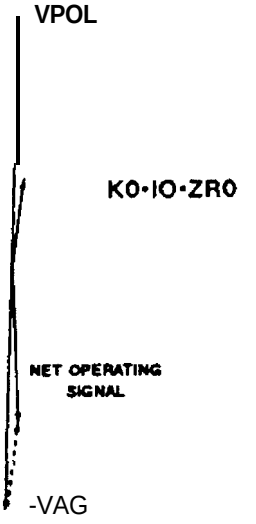
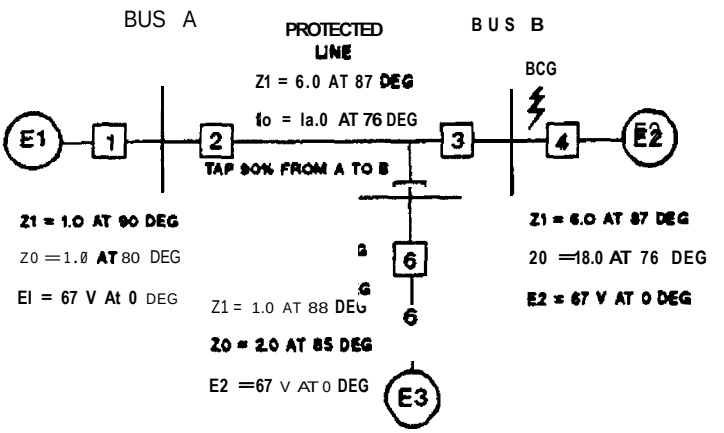


Figure 29

The reach required to cause a misoperation for this example is larger than would normally be set for the over reaching unit in a channel scheme. However, consider the three terminal line application shown in Figure 30 The currents and voltages at Breaker 3 for the external BCG fault on bus B are shown in TABLE VI.



EXTERNAL BCG FAULT
3 TERMINAL LINE

Figure 30

TABLE VI

Sequence	Phase
I1 = 26.6 A /93°	IA = 0.3 A /-96°
12 = 19.1 A /-89°	IB = 42.5 A /-13'
IO = 7.8 A /-81°	IC = 40.0 A /-161°
V1 = 28.0 V /-1.3°	VA = 84.0 V /-1.3°
v2 = 28.0 V /-1.3°	VB = 0.0 v /0°
vo = 20.0 v /-1.3°	vc = 0.0 v /0°

The voltage phasors comprising the operating signal are shown in Figure 31 for a positive sequence reach setting of 6 ohms. Note that magnitude of the zero sequence current term is larger than that of the restraint voltage VAG, and therefore this unit will operate. For the conditions of this example, the positive sequence impedance reach of the function is only set to 100% of the positive sequence impedance of the protected line which is unrealistically short for an over reaching function. The choice of polarizing signal for the ground distance relay will have little effect on the performance for this situation; other means must be used to prevent misoperation.

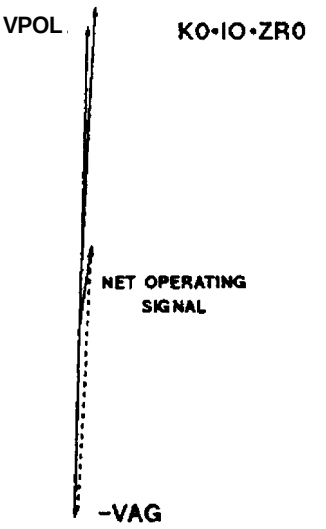


Figure 31

POSSIBLE ZONE 1 OVER REACH ON EXTERNAL LLG FAULT

Ground mho distance functions are subject to over reaching on remote double line to ground faults for certain system conditions and relay settings. Consider the system shown in Figure 32. A phase B to C to ground fault, with a fault resistance of 0.5 ohms, is applied on bus B. The resulting fault currents and voltages are shown in Table VII.

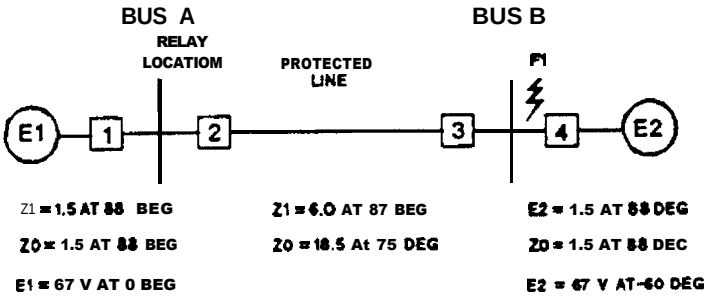


Figure 32

TABLE VII

Sequence		Phase	
I1 = 7.9 A /-66°		IA = 7.7 A j-37'	
12 = 3.4 A /31°		IB = 11.3 A /163°	
IO = 0.8 A /87°		IC = 6.1 A /39°	
Vl = 56.2 V /-4.5'		VA = 60.4 V /-8.6°	
v2 = 5.1 V /-61°		VB = 50.5 V /-124°	
vo = 1.3 v /-4.5°		vc = 58.0 V /119°	

The Zone 1 mho ground distance functions are set as shown in Table VIII. The Zone 1 is set to "see" ninety percent of the line.

TABLE VIII
Zone 1
ZRl = 5.4 ohms
ZR0 = ZRl
/ZR1 = 85°
/ZR0 = 75°
K0 = 3

VOP = (11 + I2)·ZRl + KO*IO·ZRO - VAG
VPOL = VAG

For the above conditions, the operate and polarizing signals for the Phase B ground distance function with self polarization are:

Operate : 11.2 V /-108°

Polarizing : 50.5 V /-124'

Coincidence: 164'

The operate and polarizing signals for the Phase C ground distance function with self polarization are:

Operate : 20.1 V /-87°

Polarizing : 58.0 V /119°

Coincidence: 26 °

The coincidence of these signals is sufficient to cause the phase B function to operate, while the phase C function will not operate. Thus the relay will over reach and trip Zone 1 for a fault beyond the end of the line. In order to prevent the Phase B function from operating, the reach of the Zone 1 must be reduced to approximately 4.25 ohms, which is 71 percent of the line. This condition will also cause phase selection problems in single phase tripping schemes which use over reaching ground distance functions as phase selectors.

SINGLE PHASE TRIPPING CONSIDERATIONS

INTEGRATED VS. SEPARATED SCHEMES

Single phase tripping schemes can be constructed in many different ways utilizing different types of devices. However,

the basic approaches may be divided into two categories: "Integrated Schemes" and "Separate Schemes".

Any single phase tripping scheme must be able to make two basic decisions for each fault:

a. Whether or not the fault is within the trip zone

b. Which phase or phases are faulted.

An Integrated Scheme utilizes the same measuring functions to perform both of the above, while a Separate Scheme would use one set of functions to establish whether or not the fault is within the trip zone and a separate set of functions to establish the faulted phase(s).

If one opts for an integrated scheme, then the selection of measuring units is restricted to those that can determine which phase or phases are faulted, as well as whether the fault is internal or external. For example, an Integrated Scheme could not satisfactorily employ zero sequence directional overcurrent relays for ground fault protection because by themselves these relays can not determine which phases are faulted. Ground distance relays are often used as the measuring functions in Integrated Schemes, as they are essentially phase selectors as well as measuring functions.

When one phase of a transmission line is open, an asymmetrical condition exists on the system that results in negative and zero sequence current flow throughout the power system which in turn produce negative and zero sequence voltages throughout the system. In addition, the relay voltage will be affected by the location of the potential device: line side of the breaker or bus side of the breaker. In any case, relay measuring functions that are affected by zero or negative sequence quantities must be designed to operate correctly during the open phase period.

POLARIZING VOLTAGE

When the ground distance functions are to be employed in an Integrated Single Phase Tripping Scheme, the polarizing voltage should be chosen such that the performance of the ground distance functions on the sound phases is not impaired during the open phase period. Figure 33 shows the effect of an open B phase on a phase A ground distance function for the four polarizing voltages discussed previously: this assumes no induced voltage on the open phase.

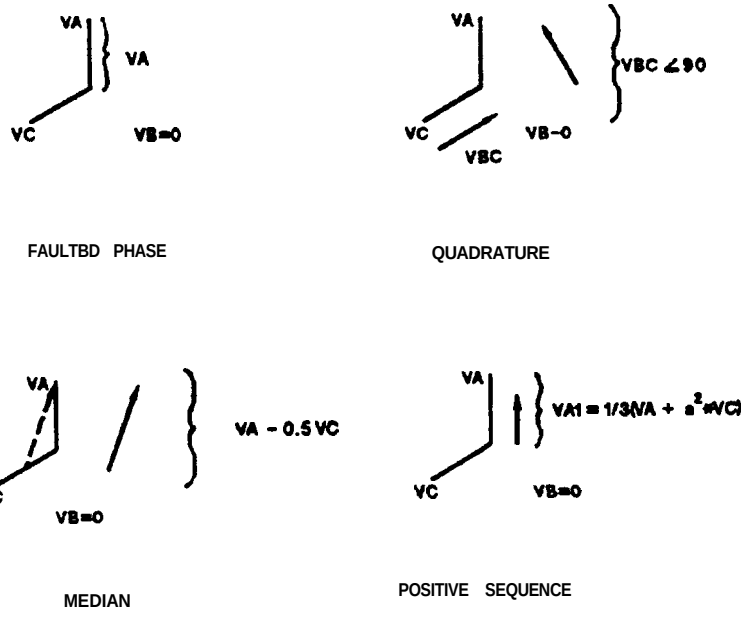


Figure 33

The per-unit magnitude and phase angle of the polarizing voltages for the conditions of Figure 33 are summarized below:

Faulted Phase:	1.000 /0°
Quadrature:	0.577 /+30°
Median:	0.880 /-19.1"
Positive Sequence:	0.667 /0°

The phase shift introduced in the quadrature and median polarized functions would cause the ground distance function to respond differently when a phase is open: for some system conditions, this may result in either failure to see a fault, or over-reach of a zone 1 element for an external fault. The faulted phase and positive sequence polarized functions, on the other hand, will respond properly whether or not a phase is open.

PHASE SELECTION

To simplify the logic required when distance functions are used in an Integrated Single Phase Tripping Scheme, several criteria must be met:

a. For single line to ground faults only the ground distance function on the faulted phase should operate;

it is also desirable that no phase distance function operates for a single line to ground fault.

b. For phase to phase faults, no ground distance function should operate.

C. For double line to ground faults, either two ground distance functions should operate; or one phase distance function should operate, preferably with no ground distance functions.

In general, the source to line impedance ratio determines the ease of obtaining correct phase selection in single phase tripping applications. With large source to line impedance ratios, phase selection is simply accomplished since it can be shown that only the proper ground distance function responds to single line to ground faults, only the phase distance functions respond to phase faults, and the phase distance functions do not respond to ground faults.

As the source to line impedance ratio decreases, the operation of the distance functions is not as well behaved. For example, it is well known that the phase distance functions will operate for close-in single line to ground faults, thus requiring some form of ground preference to prevent the phase distance function from initiating a three phase trip. The problems of correct phase selection are further aggravated by heavy load flow and, in some cases, by a low ratio of zero sequence to positive sequence source impedance.

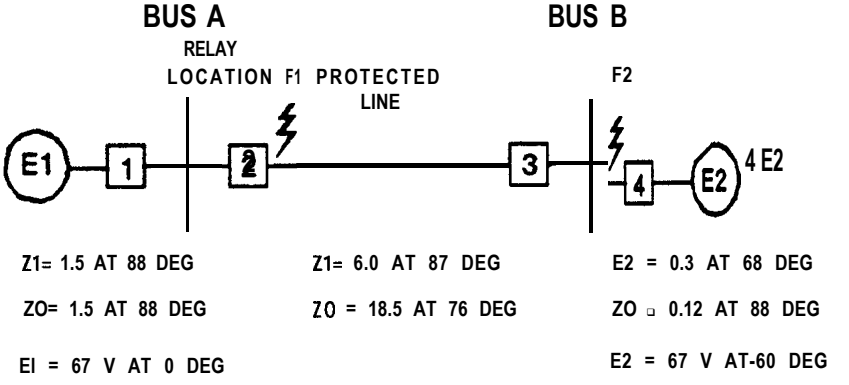


Figure 34

The following examples are based on the system of Figure 34. An over reaching ground distance mho function with a reach setting of 12 ohms at 85 degrees is assumed in each of these cases.

1. Close in single line to ground fault.

   This case assumes a phase A to ground fault directly in front of the relay location, with a fault resistance of 3

ohms. The operate and polarizing signals for the Phase C ground distance function with memory action are:

Operate: 52.7 V /44.6°

Polarizing: 61.6 V /109.6°

Coincidence: 115°

The coincidence of these signals is sufficient to cause the phase C function to operate. As the load flow increases, the phase C function is more likely to operate.

2. Remote single line to ground fault

This case assumes a bolted phase A to ground fault at the remote bus (bus B). The operate and polarizing signals for a Phase C ground distance function with memory action:

Operate: 99.6 V /196.4°

Polarizing: 61.6 V /109.6°

Coincidence: 93.2"

Again, the coincidence of these signals is sufficient to cause the phase C function to operate. As the load flow increases, the phase C function is more likely to operate; as the fault resistance increases, the phase C function is less likely to operate.

3. Remote phase to phase fault.

This case assumes a bolted phase B to phase C fault at the remote bus (bus B). The operate and polarizing signals for the Phase B ground distance function with memory action are:

Operate: 95.1 V /268.4°

Polarizing: 61.6 V /229.6°

Coincidence: 141.2"

The operate and polarizing signals for the Phase C ground distance function with memory action are:

Operate: 7.5 v /340.4°

Polarizing: 61.6 V /109.6°

Coincidence: 50.8"

The coincidence of these signals is sufficient to cause the phase B function to operate, but the phase C will not

operate. This may cause the relay system to incorrectly trip only phase B for this fault.

In general, the severity of the problem of incorrect phase selection in the above cases will be a function of the type and shape of the relay characteristic and the settings employed. As noted previously, an increasing source to line impedance ratio will reduce the probability of having phase selection problems. Of course, there are other cases that will also result in phase selection problems.

SUMMARY

This paper has presented an overview of ground distance relays in an effort to acquaint the reader with some of the design and application considerations of these relays. The relays discussed were simple two input designs; more complex designs are available. Some of these complex designs will eliminate application problems discussed in this paper. The examples used in the paper are based on the fundamental frequency components of the fault currents and voltages: that is, the effects of transients, such as caused by CCVT's, series compensation, shunt capacitance, saturated CT's etc., have been ignored.

REFERENCES

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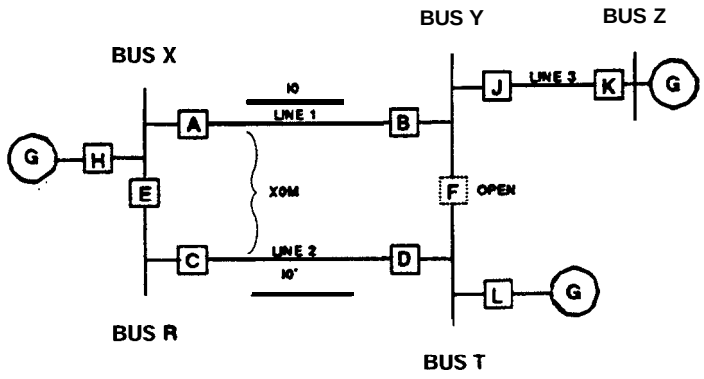
APPENDIX I

CHANGE IN REACH OF GROUND DISTANCE RELAYS CAUSED BY MUTUAL INDUCTION.

Depending on system conditions, the presence of mutual induction between two parallel lines can cause a ground distance relay to either overreach or underreach. Three cases representing different conditions are described below.



TYPICAL EXAMPLE OF MUTUAL COUPLING BETWEEN PARALLEL LINES

Figure A

Case 1: Zero sequence current In a parallel line flowing in a direction opposite to that in the protected line.

The condition to be considered for Case 1 is represented in Figure A. The apparent impedance seen by the ground distance relay is defined by the phase to neutral voltage at the relay location divided by a current. Consequently, any change in the voltage resulting from the mutual inductance, assuming no corresponding change in current, will cause the relay reach to change. For the situation in Figure A, the phase A to ground voltage for a phase A to ground fault at location X can be expressed as follows:

$$VAG = \mathbf{Il \cdot Zl + I2 \cdot Z2 + I0 \cdot Z0 - I0' \cdot Z0M} \qquad \textbf{(I-1)}$$

Adding and subtracting **I0·Zl**, and substituting Zl for Z2, yields

the following:

$$VAG = Il \cdot Zl + I2 \cdot Z2 + I0 \cdot Zl - I0 \cdot Zl + I0 \cdot Z0 - I0' \cdot Z0M \quad (I-2)$$

$$VAG = (11 + 12 + I0) \cdot Zl + I0 \cdot (Z0 - Zl) - I0 \cdot Z0M \quad (I-3)$$

$$VAG = IA \cdot Z1 + I0 \cdot (Z0 - Zl) - I0' \cdot Z0M \quad (I-4)$$

The percent change in reach, in this case overreach, when mutual compensation is not employed can then be represented by the following:

$$\text{percent overreach} = \frac{IA \bullet Z1 + I0 \cdot (Z0 - Z1)}{IA \cdot Zl + I0 \cdot (Z0 - Z1) - I0' \cdot Z0M} \times 100 \quad (l-5)$$

Assume the following system conditions as a most severe cause and refer to Figure A for system configuration:

1. Line constants of the double-circuit 345 KV tower shown in Figure 2 are:

Zl = Zl' = 0.061 +j 0.588 ohms/mile (0.038 + j 0.363 ohms/km)

z_0 = ZO' = 0.549 tj 1.964 ohms/mile (0.340 +j 1.211 ohms/km)

ZOM -0.489 tj 1.3 ohms/mile (0.302 tj 0.802 ohms/km)

2. Line R-T parallels line X-Y for 100 percent of line length.

3. The source behind breaker H contributes 50% of IO in line X-Y, and the source behind breaker L contributes the other 50% over line T-R.

4. The ratio of zero sequence current to total line current is 1:3.

For these conditions:

$$IO = IA/3 \quad (I-6)$$

$$10' = IA/6 \quad (I-7)$$

Substituting these Current values and the impedance values into equation (l-5) yields an overreach of approximately 25 percent. That is a relay set to reach 68 percent of the impedance of the protected line will now reach 85 percent of the line.

Case 2: Grounded parallel line.

The conditions to be considered in Case 2 are as follows:

1 Line R-T is out of service with three-phase grounding chains at both ends.

2. The ratio of zero sequence current in the line to total line current is 1:3.

3. Impedances are the same as in Case 1.

The phase to neutral voltage on the'faulted phase at breaker A is:

$$VAG = IA \cdot ZL + I0 \cdot (Z0 - Zl) - I0 \cdot ZM^2/Z0' \qquad (I\text{-}8)$$

The percent overreach is determined by the following equation:

$$\text{percent overreach} = \frac{IA \cdot ZL + I0 \cdot (Z0 - Zl)}{IA \cdot ZL + I0 \cdot (Z0 - Zl) - I0 \cdot ZM^2/Z0'} - 1 \quad Xl00 \qquad (I\text{-}9)$$

Substituting the current and impedance values into equation (l-9) yields an overreach of approximately 38%.

Thus, a zone-l ground distance relay, normally set for 80 percent of the protected line, would have to be set for 58 percent of the line in order to maintain the same margin.

Case 3: Zero sequence current in a parallel line flowing in the same direction as that in the protected line.

The condition for Case 3 would be represented by the system in Figure A with all breakers closed, and with an external fault on line 3. For this condition IO = IO', and assume that IO = IL/4. The phase.to neutral voltage on the faulted phase at breaker A is:

$$VAG = IA \cdot Zl + I0 \cdot (Z0 - Z1) + I0' \cdot Z0M \qquad (I\text{-}10)$$

The percentage underreach can then be expressed as follows:

$$\text{percent underreach} = \frac{Il \cdot ZL + I0 \cdot (Z0 - Z1)}{Il \cdot ZL + I0 \cdot (Z0 - Zl) + I0' \cdot ZM} - 1 \quad Xl00 \qquad (I\text{-}11)$$

Substituting,the current and impedance values into equation (I-11) indicates a percentage of underreach of 26 percent. Thus, a zone-2 relay set to reach 135 percent of the protected line would actually reach just 100 percent of the line for the conditions assumed.